New Techniques for Using Old Geophysical Logs in Reservoir Characterization: Examples from Bell Canyon Sandstones, Ford Geraldine and East Ford Units, Delaware Basin, Texas

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INTRODUCTION

Many mature oil fields in the United States have old, incomplete logging suites, and special techniques are required to maximize the information that can be derived from the old logs. In a study of the Ford Geraldine and East Ford units for a DOE Class III Oil Recovery Field Demonstration project, we developed a petrophysical approach that integrated traditional log-interpretation techniques with new methods in order to perform quantitative petrophysical interpretations using old logs. The ability to use the old logs was critical to characterizing the sandstone reservoir interval in these mature oil fields.

The Ford Geraldine and East Ford units produce from deep-water turbidite deposits of the Permian Delaware Mountain Group in Reeves and Culberson Counties, Texas (fig. 1). The main reservoir in both units is the Ramsey sandstone in the upper Bell Canyon Formation. The goal of the study is to demonstrate that reservoir characterization can optimize enhanced oil recovery (CO_2 flood) projects in slope and basin clastic reservoirs of the Delaware Mountain Group. The objective is to increase production and prevent premature abandonment of reservoirs in mature fields in the Delaware Basin of West Texas and New Mexico. Current production from Delaware Mountain Group reservoirs is only 14 percent of an original 1.8 Bbbl of oil in place, which provides a clear opportunity for improved recovery.

A key task of reservoir characterization was to quantify and map reservoir properties such as porosity, permeability, water saturation, and net pay in the two units. To accomplish this, we used traditional petrophysical methods combined with new techniques we developed in the Ford Geraldine unit. This petrophysical approach was then used to characterize the East Ford unit, providing an excellent opportunity to test the transferability of the log-interpretation methods to another field in the Delaware sandstone play.

OBJECTIVE

Primary recovery efficiency is low in Delaware Mountain Group reservoirs because of serious producibility problems, particularly low reservoir energy and high water production. Unless methodologies and technologies to overcome these producibility problems are applied, much of the remaining oil in Delaware sandstone fields will not be recovered. Our objective in conducting reservoir-characterization studies of the Ford Geraldine and East Ford units was to provide insights that are applicable to all slope and basin clastic fields in the Delaware Basin.

The technologies used for reservoir characterization included subsurface log, core-analysis, and petrophysical study. Petrophysical analysis was complicated by the incomplete nature of the logging suites in both units. In the Ford Geraldine unit, 118 wells have no porosity logs, and of the remaining 187 wells, 84 of them have only old neutron logs. Only 38 wells have both

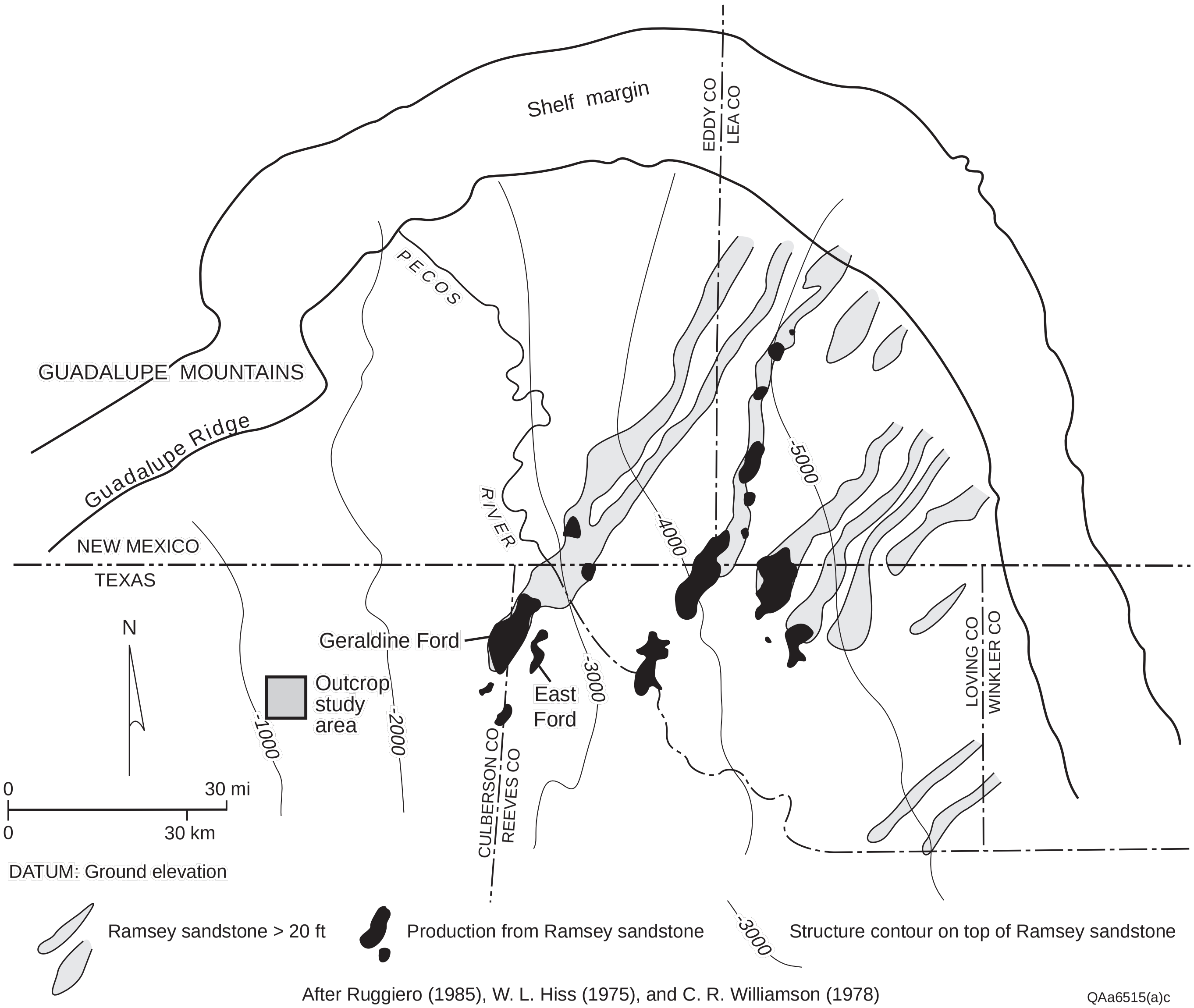

Figure 1. Location of East Ford and Geraldine Ford fields in Reeves and Culberson Counties, Texas. Production from these and other upper Bell Canyon fields in the Delaware Basin occurs from the distal (southwest) ends of east-dipping, northeast-oriented linear trends of thick Ramsey sandstone deposits. Modified from Ruggiero (1985), after Hiss (1975) and Williamson (1978).

porosity and resistivity logs. In the East Ford unit, only 26 of the 45 wells have porosity logs, and only 17 wells have both porosity and resistivity logs. The old gamma-ray and neutron logs were run by many different companies at different scales and sensitivities. Because of these problems, not all of the methods of a modern petrophysical analysis (Asquith and Gibson, 1982) could be used. Thus, the objective of the petrophysical characterization of the Ford Geraldine and East Ford units was to develop a method of log interpretation that would combine traditional techniques with some new methods and allow quantitative petrophysics to be accomplished with the old logs.

APPROACH

Our approach to quantitative petrophysical analysis using old log suites was developed in the Ford Geraldine unit because of the abundant core and core-analysis data available. We started from traditional methods of log interpretation (Asquith and Gibson, 1982) and integrated them with new methods for (1) determining true formation resistivity (R_t) from Deep Laterologs (LLD) and (2) calculating saturation exponent (n) using core porosity and water-saturation values from relative permeability curves. Much of the approach, but not all, was transferred successfully to the East Ford unit, where the technique was modified to calculate water saturation. In fields like those of the Delaware Mountain Group with poor, incomplete data, there is probably no unique solution to log interpretation that will always be successful. Instead, it is necessary to try a variety of techniques and to test their validity using all available information about the field.

PROJECT DESCRIPTION

Ford Geraldine Unit

Petrophysical characterization of the Ford Geraldine unit was accomplished by integrating core and log data and quantifying petrophysical properties from wireline logs (fig. 2); the goal

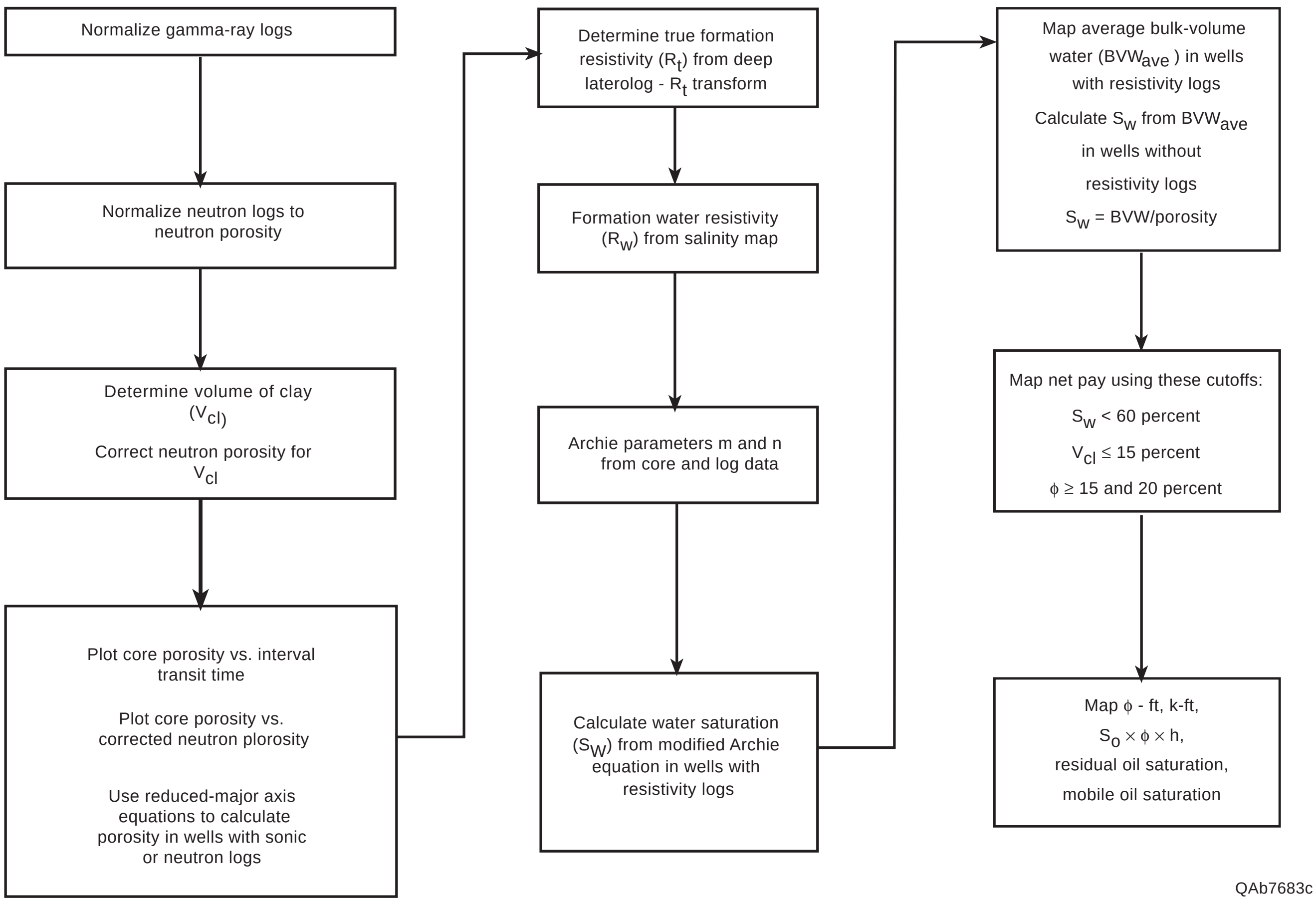

Figure 2. Flow chart of petrophysical analysis of the Ford Geraldine unit.

was a set of maps of porosity, permeability, net pay, water saturation, porous hydrocarbon volume, and other reservoir properties across the unit. The first step in the petrophysical analysis was to construct cross plots of neutron porosity and interval transit time (ITT) versus core porosity in order to determine log-to-core porosity transforms. Core porosity was plotted versus core permeability to derive a porosity–permeability transform equation. Additional tasks included: (1) mapping formation water resistivity (R_w) across the unit, (2) determining the Archie Parameters *m* (cementation exponent) and *n* (saturation exponent), and (3) developing a transform for converting resistivity measured by the deep laterolog (LLD) to true formation resistivity (R_t) when a log measuring flushed-zone resistivity (R_{xo}) is unavailable (Asquith and others, 1997).

This approach combines traditional log-analysis techniques with new methods that were developed for this study to compensate for missing data. The approach is presented in detail in Asquith and others (1997) and is summarized later.

Porosity Transforms

Because the old gamma-ray and neutron logs were run by many different companies at different scales and sensitivities, the gamma-ray logs were normalized to API units and the neutron logs to porosity units. The procedure for normalization was similar to that outlined by Barrett (1995). High and low gamma-ray and neutron values were selected for each well, however, so that the normalizing transforms each had different slopes and intercepts.

Because the Ramsey sandstone contains authigenic clays and interbedded organic-rich siltstone, it was necessary to correct for the volume of clay and silt in the calculation of neutron porosity. The clay correction was obtained from gamma-ray responses in clean sandstones versus response in organic-rich siltstones, the closest lithology to shale available in the section. Gamma-ray cutoffs for organic-rich siltstone and clean sandstone were determined at 90 and 40 API units, respectively, by plotting gamma-ray response versus interval transit times (Asquith and others, 1997). The volume of clay (V_{cl}) was then calculated by the following equations:

$IGR = (GR - 40)/(90 - 40);$

$V_{cl} = 0.33[2^{(2 \times IGR)} - 1.0]$ (Atlas Wireline, 1985),

where IGR = gamma-ray index and GR = gamma-ray value from log. The V_{cl} was used to correct the normalized neutron porosity by multiplying by $(1.0 - V_{cl})$ (Asquith and others, 1997).

Interval transit time (ITT) logs and normalized and clay-corrected neutron logs were then correlated to core porosity by reduced major axis regression (Asquith and others, 1997). The resulting equations for porosity are as follows:

Porosity (percent) = $(0.59 \times \text{ITT}) - 31.5$

Porosity (percent) = $(1.11 \times$ clay-corrected neutron porosity$) + 0.67$

Calculation of Water Saturation

Resistivity logs are electric logs that are used to determine hydrocarbon-versus-water-bearing zones (Asquith and Gibson, 1982). Resistivity logs can be used to calculate water saturation in a formation if several parameters are known, including (1) formation water resistivity (R_w), (2) true formation resistivity (R_t), (3) Archie's cementation exponent (*m*), and (4) Archie's saturation exponent (*n*) (Archie, 1942). R_w values were calculated across the Ford Geraldine unit from a map of prewaterflood salinity (Ruggiero, 1985; Asquith and others, 1997). The R_w values at 75°F ranged from 0.11 to 0.18 ohm-m, with the highest values to the southwest.

True Formation Resistivity

Calculating accurate water saturations in the Ford Geraldine unit was difficult because a deep laterolog (LLD) was commonly run without an accompanying log to measure either flushed-zone resistivities (Microlaterolog, MLL or Microspherically Focused Log, MSFL) or invaded-zone resistivities (Shallow Laterolog). These additional logs make it possible to correct the resistivities of the partly invaded zone measured by the LLD to the true formation resistivity (R_t) needed for calculation of accurate saturations. Without our applying this transform, water saturations in wells with only LLD logs would be overestimated. To overcome this problem, a linear regression transform was developed between R_t (as calculated in 12 Ford Geraldine unit wells having both shallow-resistivity measurement tools run as well as the LLD) and the LLD curve response (Asquith and others, 1997):

$$R_t = 1.3002 \times LLD + 0.3397.$$

To illustrate the importance of using this LLD–R_t transform to obtain R_t in wells having only an LLD log, hydrocarbon pore-feet thickness was calculated in the Ramsey sandstone in a typical well with and without the correction. When the transform is not used, original oil in place (OOIP) is underestimated by 155,000 barrels in a 40-acre tract (Asquith and others, 1997).

Archie Parameters m and n

Special core analyses from a well in the Ford Geraldine unit (FGU-156) included four measurements of the cementation exponent, *m*. The average of the measured *m* values was 1.88. To verify the measured values, log data were used to back-calculate *m* from ITT porosity and flushed-zone resistivity log values (Asquith and others, 1997). This method gave a value of *m* of 1.83, which was used in the modified Archie equation for the Ford Geraldine unit.

Special core analyses also measured saturation exponent (*n*), but the values were low (average =1.32) and probably not accurate. For this reason, a new technique was developed (Asquith and others, 1997) to calculate the value of *n* using core porosity and water-saturation values from relative permeability curves by the following equation:

$$n = LOG(F \times R_w/R_t)/LOG(S_w),$$

where:

n = saturation exponent,

$F = 1/\phi^{1.83}$ (ϕ is porosity),

R_w = formation water resistivity at formation temperature (0.092 ohm-m),

R_t = true formation resistivity ($R_t = 1.67 \times LLD - 0.67 \times MLL$), and

S_w = water saturation from relative permeability curves.

Values of water saturation and core porosity are from five samples on which relative permeability was measured (Asquith and others, 1997). The values of S_w represent the point where the relative permeability to water is equal to zero.

Obtaining a value for R_t in the FGU-156 well is impossible because resistivity logs were not run. Instead, R_t values were obtained from the FGU-153 well, which is 1/3 mi to the northeast of FGU-156. Obtaining R_t values from a different well was justified for the following reasons: 1) the wells are close and in the same R_w area; 2) R_t values were only selected from depths with similar porosities in both of the wells; and 3) R_t values in the Bell Canyon sandstones do not vary much.

The value of *n* that was calculated by using this method, 1.90, is more realistic than the core-measured average value of 1.32 (Asquith and others, 1997). Therefore, for the Bell Canyon sandstones in the Ford Geraldine area, water saturations should be calculated by the following modified Archie equation:

$$S_w = [(1/\phi^{1.83}) \times (R_w/R_t)]^{1/1.90}.$$

Net Pay Cutoffs

Cutoffs to define net pay for the Ramsey sandstone in the Ford Geraldine unit were established for V_{cl}, ϕ, and S_w on the basis of core and log data and published information. Accurate values for V_{cl} are difficult to determine for the Delaware sandstone because of the lack of adjacent shales. Therefore, the selection of a V_{cl} cutoff was based on the work of Dewan (1984), which suggests a V_{cl} cutoff of 15 percent for reservoirs with dispersed authigenic clay. This cutoff was used because of the common occurrence of authigenic clay in the Delaware sandstones (Williamson, 1978; Thomerson, 1992; Walling, 1992; Asquith and others, 1995; Green and others, 1996).

A plot of core porosity versus core permeability for the Ramsey sandstone in the Ford Geraldine unit resulted in the selection of the following ϕ cutoffs:

$\phi \leq 15$ percent for a permeability of 1.0 md

$\phi \leq 20$ percent for a permeability of 5.0 md

Normalization of five relative permeability curves led to the selection of a S_w cutoff for net pay at 60 percent, a value at which the relative permeability to oil is about eight times that of permeability to water. The relative permeability curves were normalized by using the method outlined by Schneider (1987).

East Ford Unit

Reservoir characterization of the East Ford unit provided an opportunity to test the transferability of the log-interpretation methods used in the Ford Geraldine unit to another Delaware sandstone field. Porosity transforms were developed for the East Ford unit, but the LLD–R_t transform and the Archie parameters calculated for the Ford Geraldine unit were used in the petrophysical analysis of the East Ford unit. It was not possible to develop these factors specifically for the East Ford unit because it has a more restricted log suite and no special core analyses.

Only 26 wells in the East Ford unit have usable porosity logs. Four other wells have cased-hole neutron logs (fig. 3), which were not used for quantitative petrophysical analysis. Because interval-transit-time (ITT) logs were the most common, only the 23 ITT logs were used for calculating porosity. Seventeen wells have both ITT and resistivity logs.

The gamma-ray logs in the East Ford unit were run in the early 1960's by several different companies at different sensitivities. They could not be directly compared, even though all but one of the logs were recorded in API units, so the gamma-ray logs had to be normalized. High and low GR values were selected for each well, giving them all different normalizing equations.

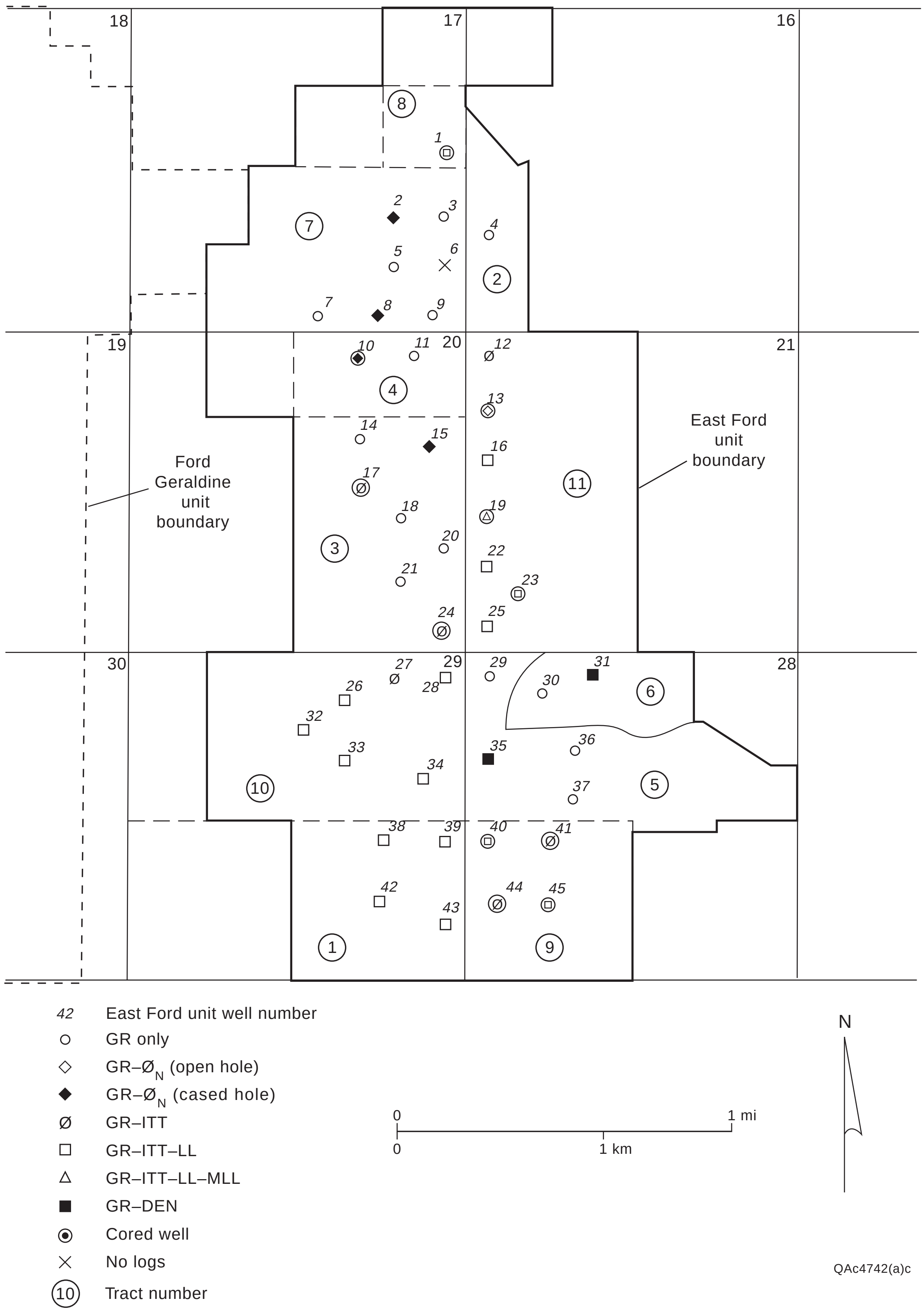

Figure 3. Distribution of geophysical log suites available in the East Ford unit.

Porosity Transforms

Core analyses from 334 samples of the Ramsey interval from 11 wells in the East Ford unit were available, so we derived new porosity transforms instead of using the equations developed in the Ford Geraldine unit. The least-squares linear regression line relating core porosity and permeability is

Permeability (md) = $0.014 \times 10^{\wedge}(0.144 \times \text{porosity})$ (fig. 4).

Core depths were shifted to log depths by using core-to-log correction factors determined for each cored well. A cross plot of ITT versus core porosity was constructed to determine the ITT-log to core-porosity transform (fig. 5). Several of the ITT logs had zones where the readings went off scale (>100 µsec/ft) because of hole washout, and these intervals were omitted from the plot of ITT versus porosity. The reduced-major-axis (RMA) equation relating ITT and core porosity was used to determine porosity in wells having ITT logs. The RMA equation is

Porosity (percent) = 0.533 (ITT) – 26.5.

Because so few ITT logs were available in the East Ford unit, logs from wells with hole washout were used in the petrophysical analysis. ITT values were extrapolated into the washed-out zones from depths where the Ramsey sandstone had good log response, and these extrapolated values were used to calculate porosity from the RMA equation.

Volume of Clay

Volume of clay (V_{cl}) was calculated from gamma-ray logs by the same method as the one used in the Ford Geraldine unit. From a plot of ITT versus normalized gamma-ray response (GR) from 16 wells in the East Ford unit (fig. 6), a GR_{cl} value of 50 API and GR_{sh} of 89 API were selected. The V_{cl} for the Ramsey sandstone was then calculated by

IGR = (GR – 50)/(89 – 50), and

$V_{cl} = 0.33[2^{\wedge}(2 \times \text{IGR}) - 1.0]$ (Atlas Wireline, 1985),

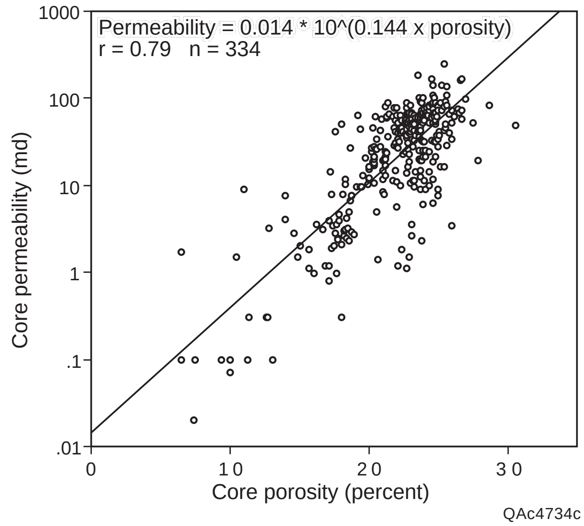

Figure 4. Cross plot of core porosity versus core permeability with porosity–permeability transform for the Ramsey sandstone in the East Ford unit, Reeves County, Texas.

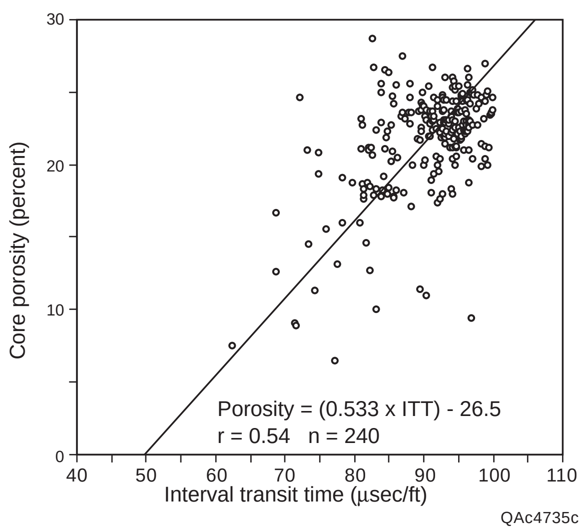

Figure 5. Cross plot of interval transit time (ITT) versus core porosity with porosity transform for the Ramsey sandstone in the East Ford unit.

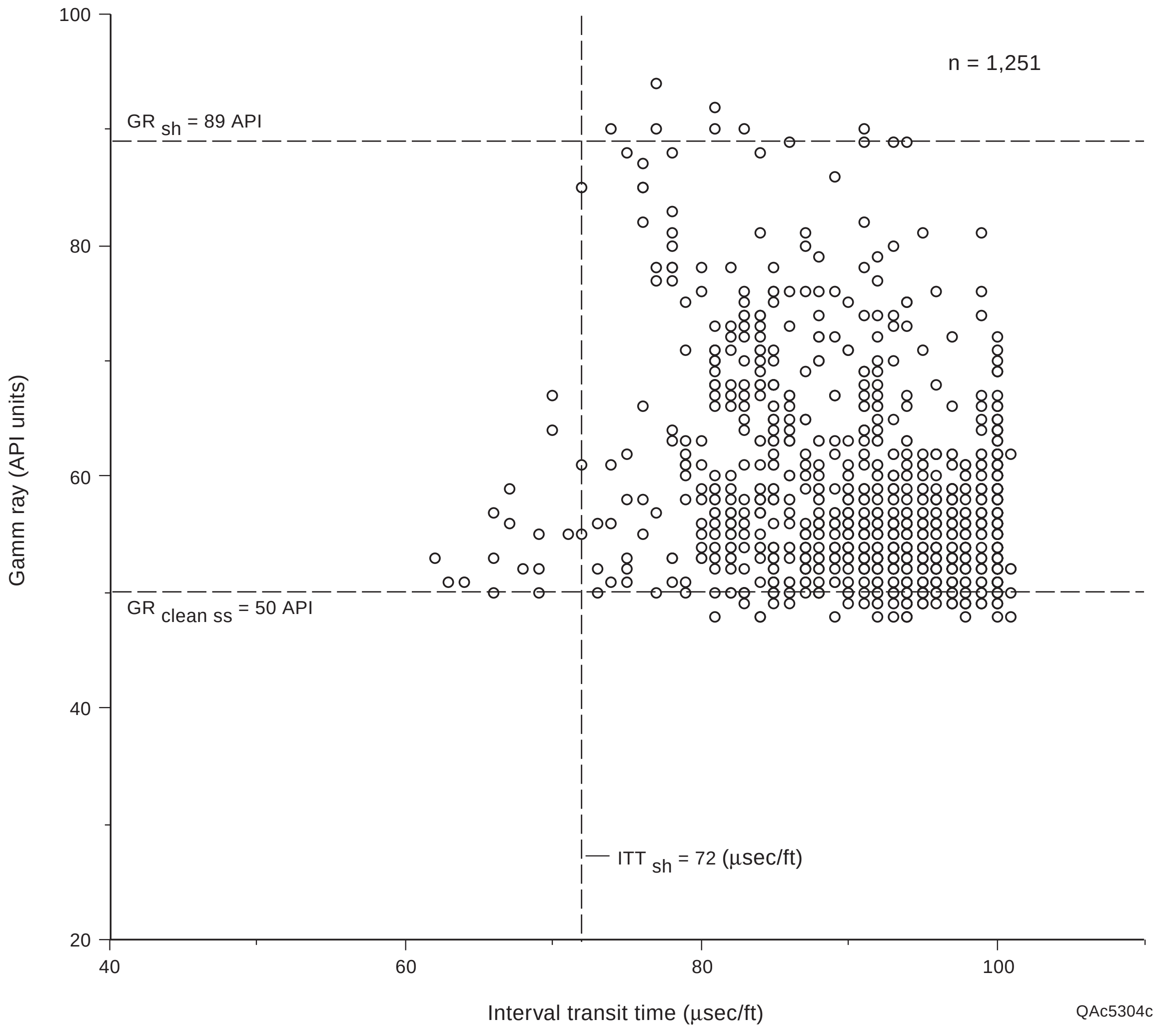

Figure 6. Cross plot of interval transit time (ITT) versus gamma ray (GR) for the Ramsey sandstone interval, East Ford unit. The data in this figure are from 16 wells, and the cross plot was used to determine GR_{cl} (50 API), GR_{sh} (89 API), and ITT_{sh} (72 µsec/ft).

where IGR is gamma-ray index. A map of V_{cl} distribution shows that low values occur in the center of the East Ford unit, and V_{cl} increases toward the margins of the unit, where the Ramsey sandstone pinches out into siltstone.

Calculation of Water Saturation

The same approach for calculating water saturation was followed in the East Ford unit as was developed in the Ford Geraldine unit. Because only one Microlaterolog was run in the East Ford unit, we used the transform developed in the Ford Geraldine unit, $R_t = 1.3002 \times LLD + 0.3397$, to correct LLD to R_t in East Ford wells.

Formation-Water Resistivity

In preparation for calculating water saturations (S_w), we estimated formation-water resistivities (R_w) across the Ford East unit from a contour map of formation-water salinities (fig. 7). Salinity data from four wells in the East Ford unit (EFU 1, 9, 24, and 37) were combined with those from the Ford Geraldine unit (Dutton and others, 1997a, b) to obtain a more regional view of water salinity. The contour map of salinity was used to assign salinity values for each of the East Ford wells. The formation-water resistivity at 75°F was then read from a chart relating NaCl concentration, temperature, and resistivity (Schlumberger, 1995, chart Gen-9, p. 1–5). Values of R_w at 75°F ranged from 0.10 to 0.12 ohm-m in the East Ford unit (fig. 7). Formation temperatures in each well were calculated from the geothermal gradient in the field and the depth of the middle of the Ramsey sandstone. Values of R_w at formation temperature were then calculated by Arp's formula (Asquith and Gibson, 1982): $R_{tf} = R_{temp} \times (\text{Temp} + 6.77)/$
$(T_f + 6.77)$,

where

R_{tf} = resistivity at formation temperature,

R_{temp} = resistivity at a temperature other than formation temperature,

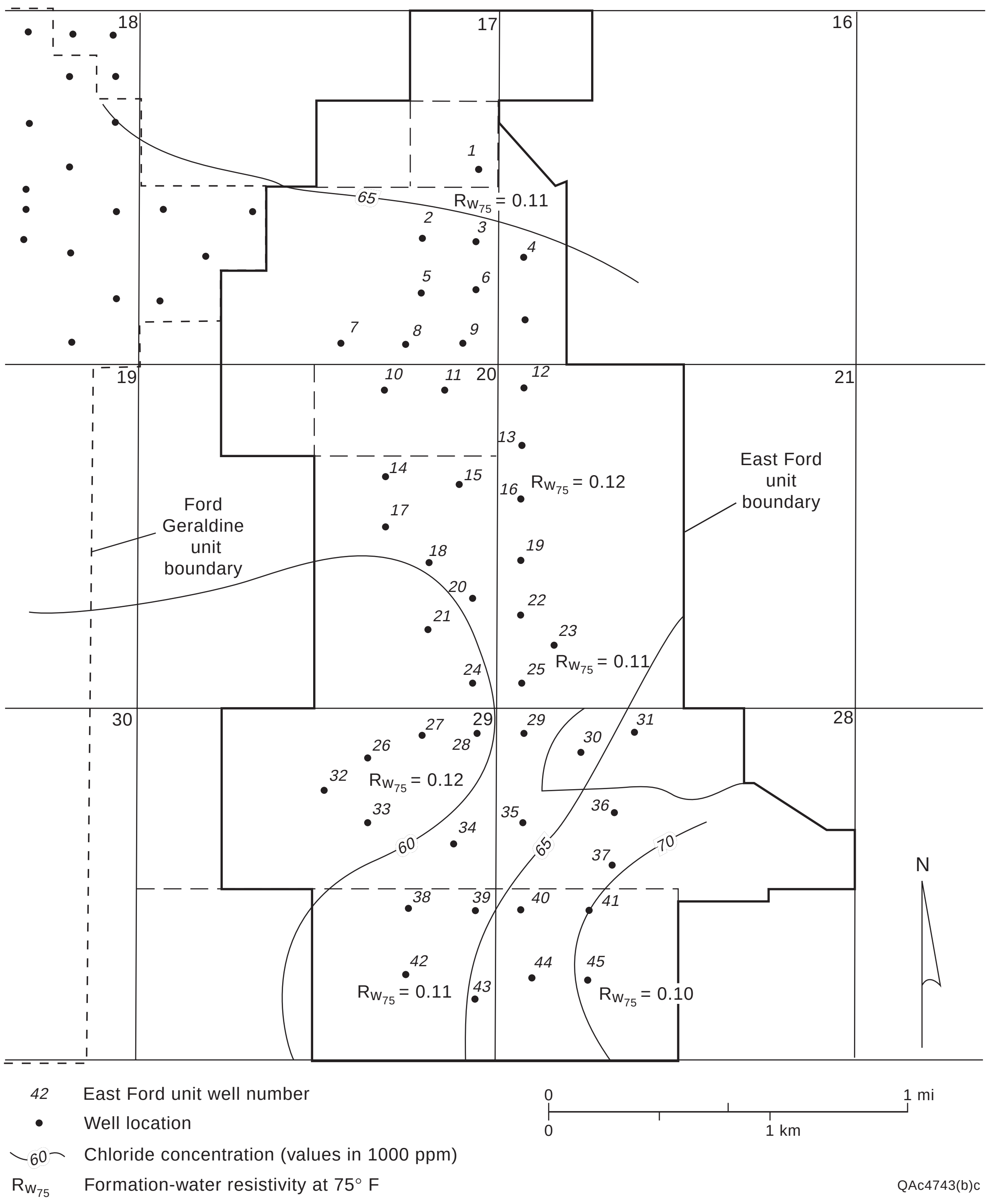

Figure 7. Isosalinity map with formation-water resistivities (R_w) at 75°F for the East Ford unit.

Temp = temperature at which resistivity was measured, and

T_f = formation temperature.

Archie Parameters m and n

No special core analyses of cementation exponent (*m*) or saturation exponent (*n*) were available from the East Ford unit, so the values of *m* and *n* determined for the Ramsey sandstone in the Ford Geraldine unit (Asquith and others, 1997) were used. Water saturations (S_w) in the East Ford unit were calculated by the same modified Archie equation that was developed for the Ford Geraldine unit:

$$S_w = [(1/\phi^{1.83}) \times (R_w/R_t)]^{1/1.90},$$

where ϕ is porosity.

Net-Pay Cutoffs

Net-pay cutoffs for the Ramsey sandstone in the East Ford Geraldine unit were selected for volume of clay (V_{cl}), porosity (ϕ), and water saturation (S_w). The same V_{cl} cutoff of 15 percent that was used for the Ford Geraldine unit was also applied to the Ford East unit. A porosity cutoff of 17.5 percent, corresponding to a permeability of 5 md (fig. 4), was selected. A change in the slope of the permeability distribution occurs at 5 md, and sandstones having permeability of ≥5 md probably represent the floodable Ramsey sandstones (Dutton and others, 1999b). No relative permeability curves were available for the East Ford unit, so the water-saturation cutoff of 60 percent was selected, the same cutoff that was used for the Ford Geraldine unit.

Saturation Distribution

As is common in Delaware sandstone reservoirs, the Ramsey sandstone at the East Ford unit had high initial S_w, and many wells produced some water at discovery. The Ford Geraldine unit averaged 47.7 percent S_w at discovery, well above the irreducible water saturation of 35 percent (Pittaway and Rosato, 1991), and the Ramsey sandstone at the East Ford unit probably also had initial water saturation greater than irreducible. Average S_w measured in 334 core analyses of the Ramsey sandstones was 47.1 percent.

Areal distribution of S_w was mapped from geophysical log data supplemented by water-saturation data from cores. First, we mapped the areal distribution of bulk volume water (BVW) according to the formula $S_w = BVW_{ave}/\phi$ using log data from wells having both ITT and resistivity logs (method described in Asquith and others, 1997). On the basis of this map, BVW values were then assigned to wells having porosity logs but no resistivity logs. Average S_w values were calculated in these wells then combined with S_w data from resistivity logs to map S_w distribution in the East Ford unit. This approach resulted in many wells in the main producing trend of the field having calculated S_w greater than 50 percent. Such high water saturations were considered unreasonable because water cuts in these wells are low, so a new method for calculating water saturation was developed.

A plot of all log-calculated S_w values versus percent water cut in initial potential tests had a large scatter in the data. Data from some wells were thought to be invalid and were eliminated if the wells fell into one of the following categories: (1) Wells completed only in the Olds sandstone; these wells had high water cuts from the Olds sandstone that could not be equated to the S_w calculated from the Ramsey sandstone. (2) Wells completed in both the Olds and Ramsey sandstones having high water cuts; these wells probably produced mainly from the Olds sandstone. (3) Wells without resistivity logs, for which S_w was calculated from the BVW map; these wells had high calculated S_w values that were inconsistent with their low water cuts. (4) Other wells with inconsistent log S_w and water-cut data. For a few wells, it was unclear why the calculated S_w was high despite a low water cut, but these inconsistent wells were also eliminated from the data base. The remaining data were used to calculate a linear regression line relating water cut to S_w (fig. 8). A map of S_w across the East Ford unit (fig. 9) was then made from the valid log-calculated S_w data (fig. 8) combined with S_w data calculated from the water-

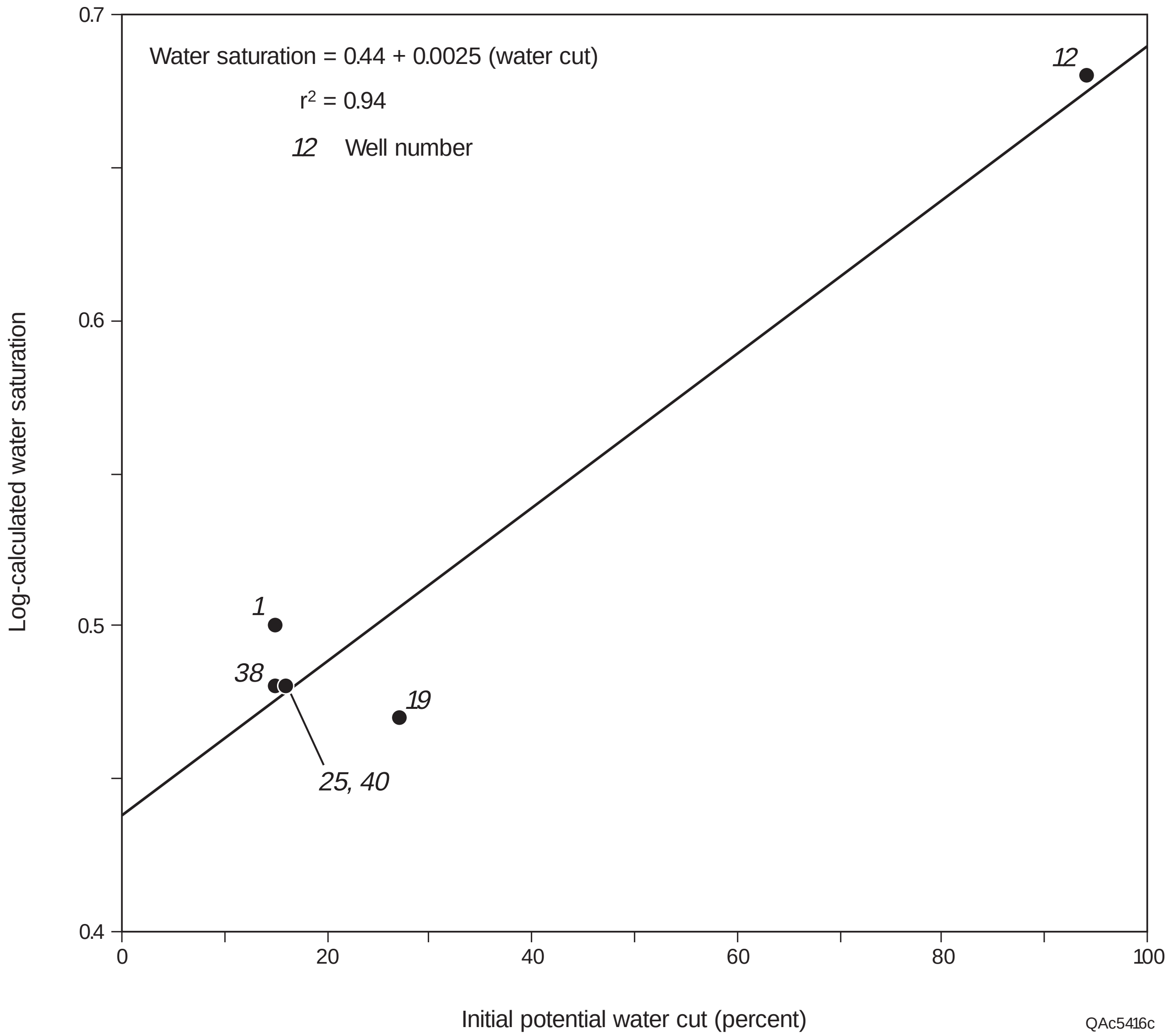

Figure 8. Plot of valid log-calculated water saturation (S_W) versus percent water cut in initial potential tests.

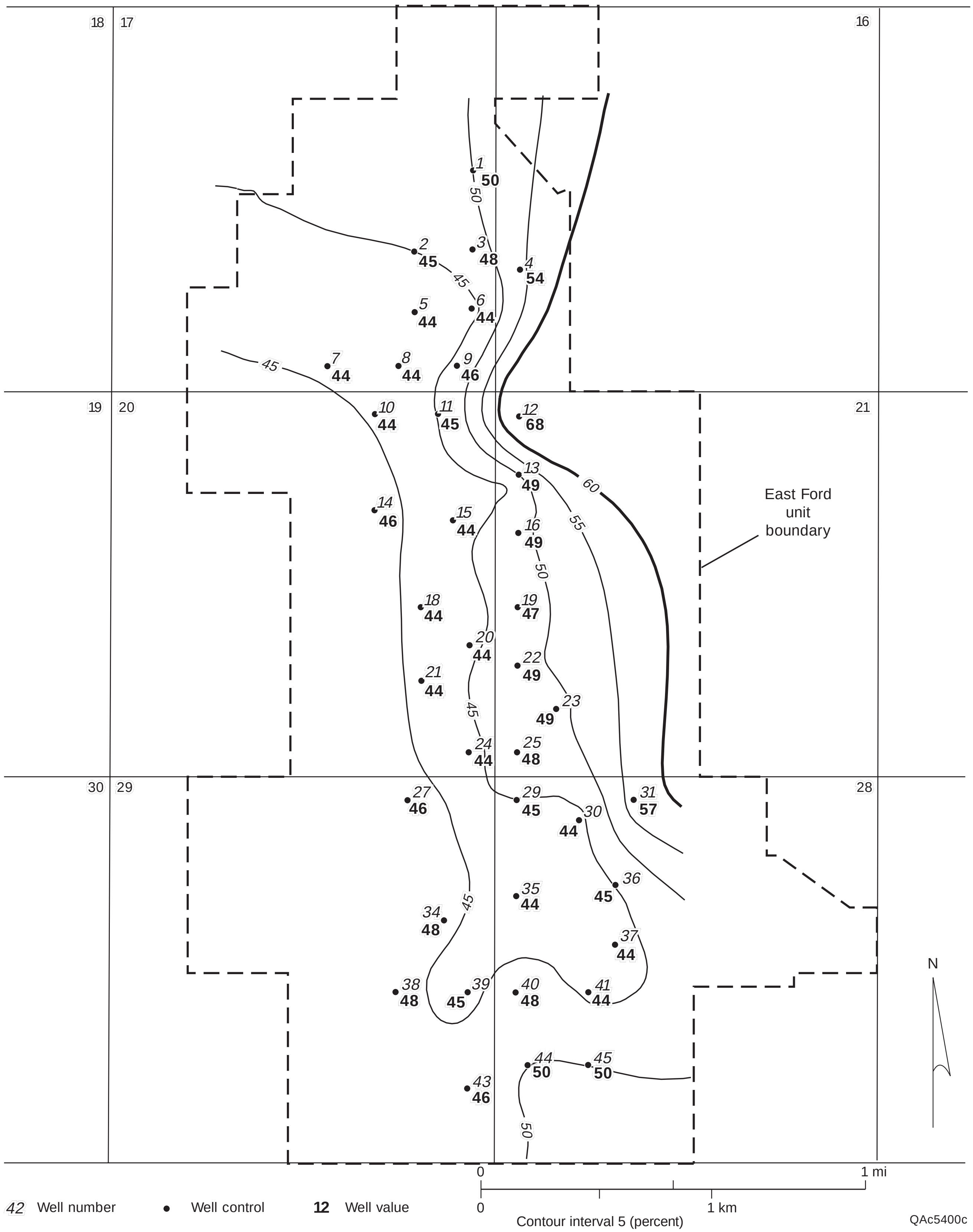

Figure 9. Map of water saturation (S_w) of the Ramsey sandstone in the East Ford unit. The S_w values are either valid log-calculated data (wells in figure 8) or calculated from the water-cut–S_w transform shown in figure 8.

cut– S_w transform. Values of S_w ranged from 44 to 55 percent across most of the field and averaged 48 percent. S_w increases to the east and northeast, which is to be expected because that direction is down structural dip.

RESULTS

Most aspects of the log-interpretation methodology developed for the Ford Geraldine unit were used successfully in the East Ford unit. The approach that was used to interpret water saturation from resistivity logs had to be modified because in some East Ford wells, the log-calculated water saturation was too high and inconsistent with the actual production. In addition, the use of bulk-volume water mapping to determine water saturation in wells having no resistivity logs did not yield results consistent with production. A cross plot of valid log-calculated water-saturation versus water-cut data provided a transform that was used to estimate water-saturation from water-cut data in wells without good resistivity logs.

The ability to do quantitative petrophysical analysis allowed us to map porosity, permeability, net pay, water saturation, porous hydrocarbon volume, and other reservoir properties in both units (Dutton and others, 1997a, b; 1999a) despite having old, incomplete log suites. This information, when combined with the primary production data, allowed us to determine the volume and distribution of remaining oil in place, which is the target of tertiary recovery.

APPLICATION

The approach to petrophysical analysis that was developed in the Ford Geraldine unit can be used in other fields in the Delaware sandstone play, as demonstrated by the successful transfer of the log-interpretation methods to the East Ford unit. Core-analysis and log data from the field being studied should be used to the greatest extent possible, but where they do not exist, the Ford Geraldine values provide a reasonable substitute. For example, if core-analysis data are available, they should be used to develop core-porosity to log-porosity transforms specific to that field, but in a field having no core analyses, the transforms developed in the Ford Geraldine unit can be used instead. Similarly, if a field has both Laterologs (LLD) and accompanying Microlaterologs, Microspherically Focused Logs, or Shallow Laterologs, an R_t –LLD transform specific to that field should be developed, but if these logs are not available, the Ford Geraldine equation can be used instead. Unless special core analyses have determined *m* and *n* in a field, the values determined for these parameters in the Ford Geraldine unit are the best data available, and water saturations should be calculated by the following modified Archie equation:

$$S_w = [(1/\phi^{1.83}) \times (R_w/R_t)]^{1/1.90}.$$

When applying this method of petrophysical analysis to a new field, it is important to compare the results with other field information, such as production data. In fields with poor, incomplete data, there is probably no unique solution to log interpretation that will always be successful. Instead, it is necessary to try a variety of techniques and to test their validity using all available information about the field.

FUTURE ACTIVITIES

In the next phase of this project we will apply the knowledge gained from the reservoir characterization to increase recovery from the East Ford unit through an enhanced-recovery program (CO_2 flood). Detailed comparison will be made between production from the East Ford unit during the CO_2 flood with the predictions that were made during the reservoir-characterization phase on the basis of simulations. This comparison will provide an important opportunity to test the accuracy of reservoir characterization as a predictive tool in resource preservation of mature fields. Through technology transfer, the knowledge gained in the study of the East Ford and Ford Geraldine units can be applied to increase production from the more than 100 other Delaware Mountain Group reservoirs in West Texas and New Mexico, which together contain 1,558 MMbbl of remaining oil.

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